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**ASSESSMENT STUDY OF DEVICES FOR THE
GENERATION OF ELECTRICITY FROM
STORED HYDROGEN**

by

**John P. Ackerman, John J. Barghusen,
and Leonard E. Link**

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Chemical Engineering Division

December 1975

FOREWORD

This study evolved out of contributions from and review by the representatives of utilities, industrial concerns, and ERDA and NASA Laboratories listed below. In particular, written assessment of the future potential and state of the art of the various generating technologies was provided by Exxon Enterprises, Inc.; General Electric Company; Rocketdyne Division, Rockwell International; Power Systems Division, United Technologies Corporation; United Technologies Research Laboratories; and Westinghouse Electric Corporation. Separate review sessions were held at Argonne National Laboratory on May 22 and 23, 1975 to evaluate fuel cell and turbine technologies. This report was reviewed in preliminary form and further developed in a workshop at Argonne July 7 and 8, 1975. The authors wish to point out the important and extensive contributions by those persons listed below, but assume full responsibility for the content of the report.

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ASSESSMENT STUDY OF DEVICES FOR THE
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ABSTRACT

A study was performed to evaluate alternative methods for the generation of electricity from stored hydrogen. The generation systems considered were low-temperature and high-temperature fuel cells, gas turbines and steam turbines. These systems were evaluated in terms of present-day technology and future (1995) technology. Of primary interest were the costs and efficiencies of the devices, the versatility of the devices toward various types of gaseous feeds, and the likelihood of commercial development. On the basis of these evaluations, recommendations were made describing the areas of technology which should be developed.

1.0 INTRODUCTION

This study was undertaken in response to a request from the Energy Storage Division of the Energy Research and Development Administration for an evaluation of alternative methods of generation of electricity from stored hydrogen. This evaluation centered primarily on fuel cells and various turbine systems, since only those devices which are likely to be brought to commercial use within twenty years were to be considered. Because of the length of time required for the development of magnetohydrodynamic (MHD) systems, these systems were not evaluated in depth. Contributions from experts in the areas of fuel cells and turbine systems were solicited and these contributions form the basis of the technical evaluations made herein. Also, in order to judge the relative importance of the technical, environmental, and economic characteristics of the various generating systems, representatives of several utilities were asked to evaluate and criticize the content of the report.

The focus of this study is on the conversion of hydrogen to electricity only. Although it is recognized that the systems aspects of a hydrogen-storage scheme for utility production of electrical power are of critical importance, the intent of this study is to provide an evaluation specifically of the generating part of the system.

Upon consideration of other aspects of the system, the following approaches were taken. First, when data about other system components were needed, they were obtained from existing literature; no effort was made to develop independent information. Second, the fuel and oxidant fed to the generating device was specified to represent the range of feeds that would exist in various storage systems. Third, where the characteristics of the generating devices required a storage system of a specific type, this was discussed.

The need for energy storage in a utilities system follows from the nature of the varying electrical demand, and the characteristics of the generating equipment available to meet the demand. The demand curve of one utility is presented in two ways in Figs. 1.1, 1.2, and 1.3. As can be seen Figs. 1.1

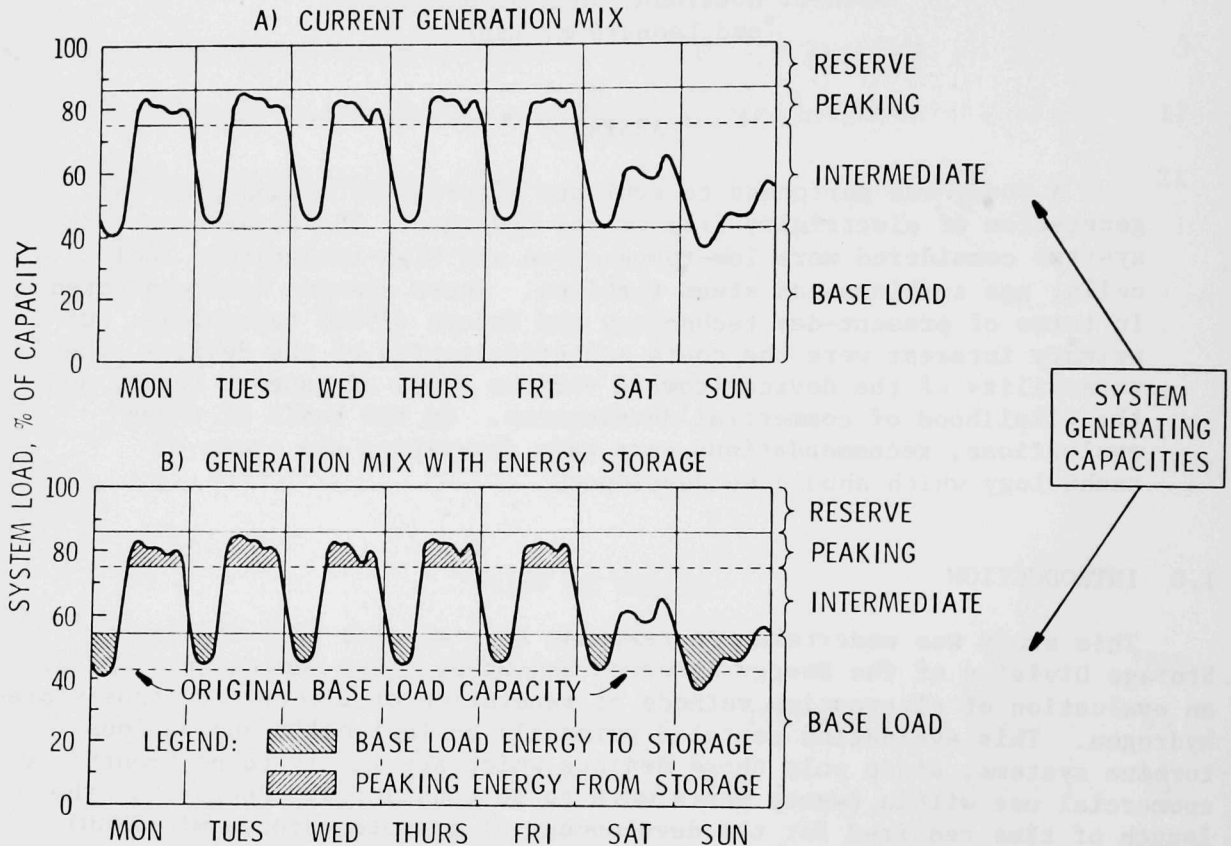


Fig. 1.1 Weekly Load Curve of an Electric Utility

and 1.2, there are seasonal, weekly, and daily variations in demand. This varying demand results in maximum load on generating capacity for only a few hours each year, tapering to less than 40% of maximum load that is required at all times, as is shown in Fig. 1.3. Three regions under the curve in Fig. 1.3 usually are distinguished. The base load region is that part of the **generating capacity which can be on stream nearly all the time**. Base load generators are not required to have a widely varying output, since they tend to be run continuously at or near rated power. They must produce electricity at minimum cost, because they generate the largest fraction of the total electric energy output. These base load generators are typically nuclear and large fossil steam plants. The capital cost of these generators is spread over a large number of operating hours per year; hence, a premium in capital cost can be paid to use inexpensive fuel and to achieve high efficiency.

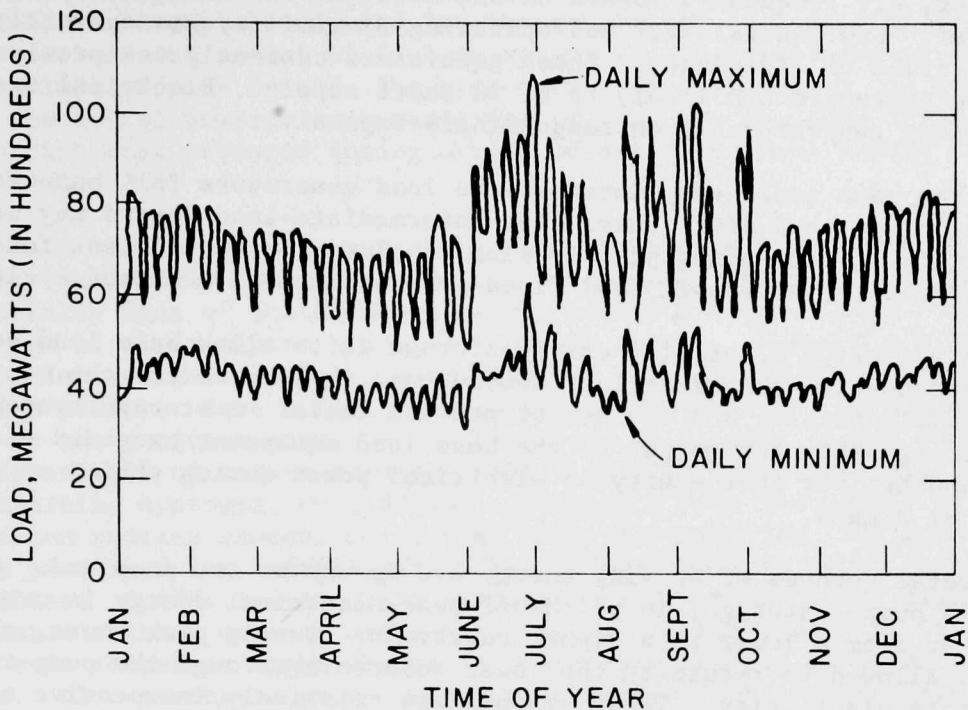


Fig. 1.2 Variation in Daily Maximum & Minimum Loads
(From one Utility)

At the other extreme, peaking generators operate relatively few hours per year and must, therefore, have a relatively low capital cost. These generators are brought on-steam rapidly to meet the variations in load as

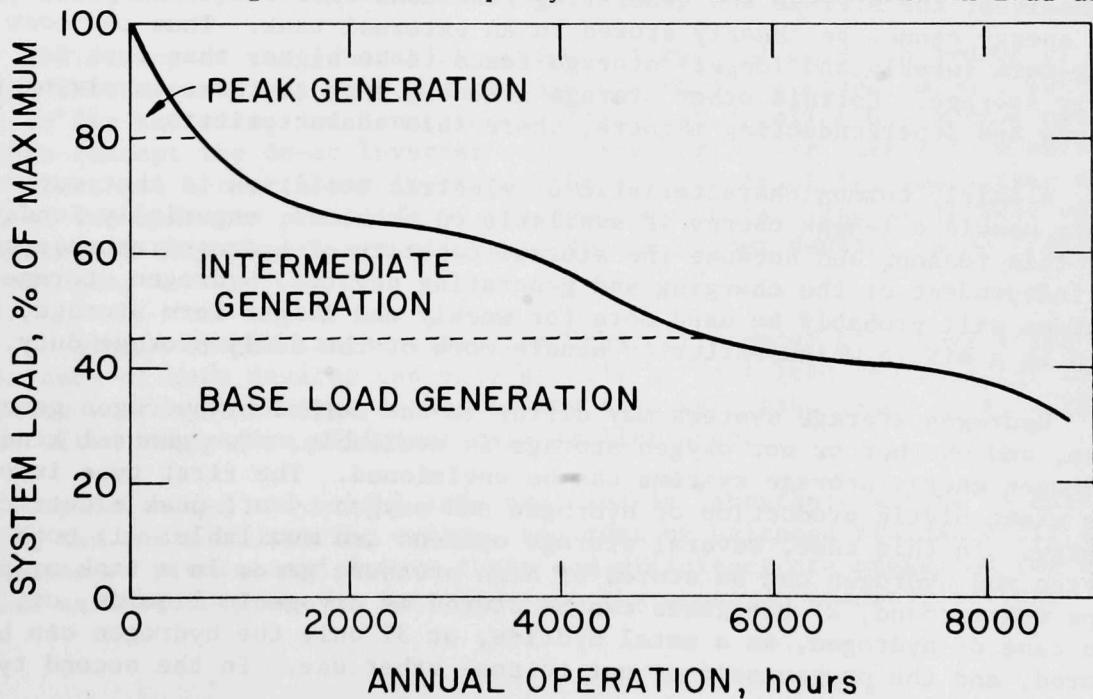


Fig. 1.3 Annual Load Duration Curve of an Electric Utility

they occur, are frequently turned on and off, and at times are operated at part power. Low capital cost and operating flexibility are currently achieved at a sacrifice of efficiency. These generators currently use premium fuels which are expensive and likely to be in short supply. Electrical energy from peaking generators is correspondingly expensive.

As the name indicates, intermediate load generators fall between these extremes in cost and efficiency. The intermediate-load demand may be met by a variety of generating plants, such as older, less efficient fossil steam generators, or fossil fuel fired gas turbines of combined cycle design.

The objective of utility energy storage is to allow base load generators to provide more of the electrical demand, and thereby reduce the cost of delivered electricity and the use of premium fuels. A storage system would accept energy when the output of the base load equipment exceeded electrical demand and deliver that energy as electrical power during period of peak electrical demand.

Several methods of storing energy are in use or are proposed. One such system is pumped storage, in which off-peak electrical energy is used to pump water from a lower to a higher reservoir. During peak hours, that water is allowed to return to the lower reservoir through the pump-turbine to generate electricity. These systems are relatively inexpensive and return about two thirds of the energy input, but the number of sites available for the reservoirs is limited and there is marked public opposition to their development. Another method is to store electrical energy by converting off-peak ac power to dc, using the dc power to charge batteries, and then discharging the batteries through a converter to provide ac power during periods of peak load. Energy return for a battery system might be about the same as pumped hydro.¹ All the energy must be stored within the batteries themselves; the storage and generating functions cannot be decoupled, *i.e.*, the energy cannot be cheaply stored in an external tank. Thus the cost of long-term (weekly and longer) storage tends to be higher than that for daily storage. Certain other storage schemes, such as those involving flywheels and superconducting magnets, share this characteristic.

A fairly common characteristic of electric utilities is that much of their usable off-peak energy is available on weekends, especially Sundays.² For this reason, and because the storage capacity of hydrogen storage systems is independent of the charging and generating devices, hydrogen storage systems will probably be used more for weekly and longer term storage, perhaps in a mix in which batteries handle more of the daily storage duty.

Hydrogen storage systems may differ in the method of hydrogen generation, and whether or not oxygen storage is available. Two general kinds of hydrogen energy storage systems can be envisioned. The first type involves the electrolytic production of hydrogen and oxygen by off-peak electrical energy. In this case, several storage options are available: 1) both the oxygen and hydrogen can be stored as high pressure gases in a tank or perhaps underground, 2) the gases can be stored as cryogenic liquids, or, in the case of hydrogen, as a metal hydride, or 3) only the hydrogen can be stored, and the oxygen sold or put to some other use. In the second type

of hydrogen storage system a hydrogen-rich fuel is synthesized continuously (from coal, for example) and used for the generation of electricity. During off-peak periods the amount of fuel in excess of electrical demand is stored. During periods of peak demand, the stored fuel is released to the generator to make electrical power. As a variation of this system, some or all of the hydrogen-rich fuel produced during period of low electrical demand can be sold.

In this study, four classes of hydrogen feed were specified. Case A represents the storage of electrolytic hydrogen and oxygen. The feed would be essentially free of contaminants except possibly water. Case B represents the storage of electrolytic hydrogen, but not oxygen. Cases C & D are coal- or refuse-derived gaseous fuels used with air (or perhaps oxygen from an air separation plant). Case C fuel is relatively pure hydrogen from a shift reactor at the gasifier site. It is specified to contain ≤ 1 ppm of sulfur compounds and $\leq 1\%$ of carbon oxides. Case D fuel is unshifted gasifier output, containing hydrogen, CO, and CO₂. Depending upon the nature of the gasification process chosen, CO₂ levels might be quite low (10% from the CO₂ acceptor process,³ for example) or it may be desirable to scrub the CO₂ at the gasifier. Sulfur levels could vary up to 100 ppm and there might be considerable methane in some processes. As an interim source of Case C or D fuel, some companies might choose to synthesize the gas from petroleum products. Also synthetic products, such as methanol and methane from coal or refuse, could be processed to yield Case C and D feeds by steam reforming and, in Case C, by the water-gas shift reaction.

The important characteristics of a generating device for use in a hydrogen energy storage system can be divided into those directly related to storage cost and those related to integration of the storage system with the rest of the utility network. Cost-related factors are efficiency, capital cost, life, and operating and maintenance costs.

Efficiency of the generating device not only affects the amount of energy that must be put into the storage system for a given output, but it acts to fix the size, and hence the capital cost of all other system components (except the dc-ac inverter or alternator). For this reason money and effort are better spent improving the efficiency of the generating device than of the hydrogen producing or storage components. The efficiency values presented in this report are all based on the Higher Heating Value (HHV) of hydrogen.

No single number can be cited for "the efficiency" of a generating device. Efficiency of many devices can vary greatly at part load and at rated load. Efficiency of a given type of device may also vary with rated size, larger units often being more efficient than smaller ones.

Capital costs and useful life are clearly important factors in determining the costs of storing energy, and must be balanced against efficiency. Estimates of present and future costs and efficiency are presented for each device so that they may be factored into the economic tradeoff for the

storage system as a whole. The projected cost values for devices presented in this report are for equipment as it would be sold in a developed commercial market.

A number of other characteristics of generating devices are less directly related to operating cost, but nonetheless are important in considering the use of a particular device within the utility network. Pollutant emission is one of these. If a device has low thermal, noise and chemical pollution, it is much more flexible in site requirements, and could be sited near or within urban centers where loads are heavy and transmission costs are highest. Another essential characteristic is the ability of the generator to respond rapidly to varying load. The nature of "peak shaving" energy storage use is such that the storage system must satisfy only a varying load, and would operate at part power or zero power most of the time, so that startup should be fast. Also, the power output of the device may be required to change rapidly throughout its duty cycle to follow the changing load. Another characteristic is modularity which allows flexibility of sizing and siting and acts to reduce installation cost, which can in some cases approach the capital cost of the generator itself.

Evaluations were performed on low-temperature and high-temperature fuel cells, gas turbines, and steam turbines for both present-day technology and future (1995) technology. Of primary interest were the costs and efficiencies of the devices, the versatility of the devices toward various types of gaseous feeds, and the likelihood of commercial development. On the basis of these evaluations, recommendations were made describing the areas of development which should be supported.

2.0 FUEL CELLS

2.1 Present Status

2.1.1 Cells with Aqueous Acid Electrolyte

Of all fuel cell systems the aqueous acid electrolyte systems are the most highly developed, and the best estimates of cost and life have been made for these systems. The cells operate in the temperature range from 175 to 200°C using a phosphoric acid electrolyte and supported noble-metal catalysts at very low loadings.

The cells are essentially insensitive to CO₂, which acts only as an inert diluent to the fuel or air stream. Any CO present in the fuel stream decreases the activity of the noble metal catalyst, but at these temperatures acceptable catalyst activity remains at CO levels of a few tenths of one percent. Therefore, these cells are an excellent choice for Case C fuels - those containing up to one percent carbon oxides. For CO levels much above one percent (Case D fuels), it will be necessary to add a "shift" converter before the fuel reaches the fuel cell, to promote the water-gas reaction in which CO reacts with steam to form CO₂ and hydrogen. The shift converter is almost thermoneutral; hence, it has little effect on generator efficiency. The output of the shift converter contains about 1% CO; this would be reduced to tolerable levels by including a methanator to combine CO with some H₂ and

form methane, or by adding air or oxygen and selectively oxidizing the CO to CO₂ on a catalyst.

Since phosphoric acid cells are relatively well developed, it may be desirable to use them, at least initially, in systems providing Case B and Case A feeds. In Case A, cathode performance would increase considerably, and higher efficiency would be accompanied by higher power density, which translates to lower cost. Estimated cost and efficiency data on the four feeds are as follows:

	<u>Case A</u>	<u>Case B</u>	<u>Case C</u>	<u>Case D</u>
Capital Cost ^a , \$/kW	160	225	225	225
Efficiency (HHV), % ^b	44	42	42	38

These data are probably as reliable as any available for utility-type fuel cells, but it must be noted that no units are commercially available at present and are not likely to be before 1980. On the other hand, the development programs for these cells have been much larger than for any other type, and they are closest to commercial delivery.

Estimated (goal) lifetime is 40,000 hr of operation (with 5% loss of efficiency in that period). Although this lifetime appears to be technically feasible, and much evidence exists to support optimism on this point, the lifetime goal has not been demonstrated. Actual lifetime demonstration will require five years of operation.

2.1.2 Cells with Membrane Electrolyte

The electrochemistry of membrane electrolyte cells is basically the same as that of phosphoric acid cells, but the acid functional groups are chemically bounded to a submicroscopically fluorocarbon plastic. This provides some advantages in physical control of the electrolyte and in cell construction; for example, relatively thin electrolyte sheets can withstand substantial pressure differences. However, since the effective molecular weight of the electrolyte is high, there is virtually no water vapor pressure suppression, and both the fuel and the oxidant must be saturated with water. As the cell operating temperature is raised, the fuel and oxidant streams are diluted to an increasing extent with water. This effect is especially noticeable at the air electrodes and has limited the operating temperature of these cells to about 150°C. For use with fuels containing CO, higher temperatures are desirable, because the poisoning effect of CO on noble-metal anode catalysts is mitigated. At 150°C, CO levels must be reduced to much lower levels than at higher operating temperatures of, perhaps, 175 or 200°C; therefore, more extensive CO removal is required than for the phosphoric acid cells.

Useful life and efficiencies are quite good. For small, 4-cell experi-

^aCapital cost is estimated price, including inverter, FOB factory.

^bEfficiency expected after 40,000 hr of operation at temperature.

mental units operated at 80°C and ~ 120 A/ft², lifetimes of more than 34,000 hr have been demonstrated on pure hydrogen and oxygen with essentially no loss in performance. Manufacturing cost is currently projected to be very high (\$65-70/ft² or \$150-160/kW for cells alone, operating on oxygen), largely because of high (4 g/ft²) platinum loadings, complex cell parts made of expensive niobium and titanium, and relatively expensive electrolyte. For operation on air, present performance results indicate a much higher cost, because of limited power density.

2.1.3 Cells with Aqueous Base Electrolyte

Two characteristics stand out in this system. The first is superior electrochemical performance, even at modest temperatures. The second is great sensitivity to CO₂. If this system is developed, it would probably be the cheapest and most efficient type of all, since temperatures are low and materials can be cheap and easily mass produced. Noble metal catalysts would probably not be required, yet high efficiency is expected. The reason that conventional base electrolyte systems are not as well developed as acid electrolyte systems is that either (1) CO₂ in the fuel and oxidant streams must be scrubbed to considerably less than the parts-per-million level or (2) some provision for preventing carbonate deposition, especially within the porous gas electrode structure, must be developed. CO₂ from other sources, such as from materials of construction or from diffusion through feed hoses, etc., would have to be similarly controlled. This is a serious problem, and one not easily overcome.

However, a major investigation is under way to develop an alkaline fuel cell that can tolerate CO₂. The decrease in cell performance due to carbonate formation is overcome through an integrated cyclic-decarbonation concept analogous to the power and exhaust cycles of piston engines. Each cell automatically cycles between a power-generating phase and an electrolyte-decarbonation phase. Although fuel is consumed during decarbonation, the alkaline conditions during the power cycle lead to highly efficient electrode reactions which offset this factor. As a result, alkaline systems with provisions for decarbonation promise to be more efficient and generate higher power than systems currently developed.

2.1.4 Cells with Molten Carbonate Electrolyte

These cells operate at temperatures above 600°C, where the activity of the catalyst (not a noble metal) is very high, and most of the energy loss in the cell is due to electrical resistance, especially in the electrolyte. Carbon monoxide is not only tolerated, but is actually consumed by these cells; hence, they are well suited for use with fuels containing more than 1% CO. If a carbonaceous fuel is used, the fuel conditioning system for converting that fuel to hydrogen can be much simpler than for the lower temperature cells.

Carbon dioxide must be furnished to the cathode of molten carbonate cells, theoretically in the ratio of two moles of CO₂ per mole of oxygen.

This CO_2 could come from the anode exhaust if a carbonaceous fuel was stored and fed to the cell, but if Case A, B, or C feed was used, it would have to be supplied from an external CO_2 makeup system and probably also recycled from the anode exhaust. This CO_2 is required because $\text{CO}_3^{=}$ ions are the current carriers in the electrolyte. They are converted to CO_2 at the anode by Reaction 1, and hence must be resupplied to the electrolyte at the cathode by Reaction 2:



If CO_2 is not supplied at the cathode, the electrolyte in that part of the cell becomes rich in oxides, and thereby impairs the performance of the cell. In addition to carbon dioxide management problems, historically problems with corrosion have been encountered in the high temperature molten carbonate environment of this cell. The present status of this system is that it is under active development at a "research" level. Large batteries have not yet been produced, but if progress continues to be satisfactory, commercial production might occur in the early to mid 1980's.

2.1.5 Cells with Solid Oxide Electrolyte

Solid oxide cells operate at a temperature near 1000°C , using doped zirconium oxide electrolytes, which are oxide ion conductors. Theoretical efficiencies of these cells are slightly lower than room temperature cells, but this is compensated for by two factors: (1) the heat rejected is at very high temperature and hence is very useful and easily recovered; and (2) at these temperatures, polarization losses are nearly nonexistent, CO is consumed, and even sulfur compounds are tolerable at relatively high levels (50 ppm), so that very high fractions of theoretical efficiency can be achieved, even with relatively impure fuel. At present, development effort on solid oxide cells is at a very low level, because of several basic problems in materials which must be resolved before engineering development can be undertaken. The greatest of these problems is finding an intercell connector material that can withstand both the anode and cathode chemical environments and electrochemical potentials, that has a high electronic conductivity, and that is leak-free and has a thermal expansion compatible with the rest of the cell.

If these problems can be overcome, this type of cell would be usable in principle with virtually any feed. At that time one would have to obtain necessary data to consider how best to match the high temperature and the availability of high quality reject heat to the needs of a storage system.

2.2 Future Developments

2.2.1 Cells with Acid Electrolytes

The major developments seen for acid electrolyte cells are (1) verification of projected costs, lifetime, and performance of commercial-size fuel cell generating systems, and (2) development of manufacturing

facilities and significant commercial use of these systems. Depending upon the level of investment assumed, the technical characteristics could be essentially verified by the end of 1980. Early verification of this point is likely because the degradation mechanisms within the cell, primarily the loss of catalyst activity, are thought to be sufficiently well understood to allow extrapolation from performance at, for example, 10,000 hr to performance at 40,000 hr. By means of gradual engineering improvements, United Technologies Corp. predicts future increases in efficiencies of phosphoric acid systems of about 4% for Case B and C fuels and about 6% for Case A and D fuels, at constant cost (1975 dollars). It should be realized that cost and efficiency can always be traded, one for the other.

United Technologies estimates that bringing these cells to the point of commercial use would require expenditures of \$5 to 10 million per year, once the "research and development" phase is essentially complete. It is probably possible to develop manufacturing capability for significant commercial sales by early or mid-1980's.

2.2.2 Cells with Membrane Electrolyte

Future advances in this technology would almost certainly be directed toward decreasing costs. Catalyst loadings can probably be decreased by at least an order of magnitude, and the expensive metal components of the cells might be replaced by less expensive materials, perhaps by other metals. Membrane cost would still be high, but it may be possible to develop a membrane material which not only is less expensive per kilowatt but is capable of higher temperature operation, so that CO control is less critical. High temperature operation would still be limited by the necessity of maintaining water vapor pressure at saturation; therefore the estimates below for cost and efficiency include CO removal equipment in Cases C and D. For Case D, a shift reactor and some CO₂ scrubbing before the feed reaches the cell are included in the manufacturer's estimates. Removal of CO₂ is not absolutely necessary, but allows higher utilization of the H₂ content of the fuel, and therefore was deemed economically desirable.

General Electric Company estimates that future selling costs and efficiencies for a membrane electrolyte generator, including inverter and fuel processing, as required, are as follows:

	<u>Case A</u>	<u>Case B</u>	<u>Case C</u>	<u>Case D</u>
Cost/kW	\$130	\$200	\$200	\$220
Efficiency (HHV)	51%	44%	43%	43%

2.2.3 Cells with Aqueous Base Electrolyte

The inherently superior electrochemistry of this system should be translatable into lower costs and higher efficiencies than the acid and membrane electrolyte cells can provide. Presumably base electrolyte cells would be used for Case A generators, where electrolytic hydrogen and oxygen would be available. Even for Case A feeds, a significant difference of

opinion exists on the projected costs and performance of base electrolyte cells, with opinions of the fuel cell experts consulted in this study about evenly divided between the two estimates shown below. This difference is illustrative of the danger in projecting the characteristics, especially costs, of undeveloped technologies. For Case B, a CO₂ scrubber is required. It should be possible to remove sufficient CO₂ from air to allow operation of a type of cell with a circulating electrolyte. Exxon estimates the cost increment as \$10 to \$20/kW, consistent with the lower cost technology of Case A. They are studying the extension of base electrolyte technology to Case C and D feeds, but their proprietary position and the state of development of the technology make cost and performance projections inappropriate at this time. Future projected costs and efficiencies for a commercial system are:

	<u>Case A</u>	<u>Case B</u>
High Cost/kW	\$150	-
Efficiency (HHV)	54%	-
Low Cost/kW	\$90	\$110
Efficiency (HHV)	60%	52%

2.2.4 Cells with Molten Carbonate Electrolyte

This type of cell would be applied to a carbonaceous fuel feed, because of the CO₂ requirement discussed in Section 2.1.4.; hence, Class D feed is the appropriate application. This feed could come from an unshifted output of a coal or refuse gasifier or from reformed synthetic carbonaceous fuels. Depending upon rate of the development of clean coal fuels and the availability of petroleum products, liquid distillates could be consumed in a interim period with essentially no difference in the power plant design or performance from synthetic carbonaceous fuels.

Because of the high-temperature corrosive environment, and because of the need for CO₂ management in this type of cell, a substantial development effort is required, perhaps more than with any aqueous type of cell. However, noble metals are not required to give electrochemical performance superior to lower temperature cells, and fuel processing will be simpler and less expensive. The result is that efficiency at the same cost is likely to be 4-5% higher than phosphoric acid systems. Estimated cost is \$225/kW, and efficiency is estimated to be 51%.

2.2.5 Cells with Solid Oxide Electrolyte

The high quality waste heat associated with these cells should be utilized, and this might be best accomplished by integration with a coal gasifier. However, some bottoming cycle might be applied to recover this heat. Recent research⁴ indicates that electrolytes that operate at a lower temperature may become available. These might ease the problems, especially with materials, that are inherent in high temperature operation. Even so, the high operating temperature of the cells and the availability of high quality "reject" heat points the way more toward continuous rather than intermittent or cycling use of this system. Adaptation to a storage system would require considerable study.

Efficiency of these cells is dependent mostly on whether oxygen is available, since Case C and D fuels are consumed directly. The HHV efficiencies (not including waste heat recovery) are predicted to be

	<u>Case A</u>	<u>Case B</u>	<u>Case C</u>	<u>Case D</u>
Efficiency, HHV	47%	45%	45%	44%

Cell materials are relatively low in cost, but estimation of delivered or even manufactured cost is entirely premature.

2.3 Summary of Cost and Efficiency Data for Fuel Cells

Table 2.1 present a summary of the cost and efficiency data for fuel cells as a function of feed type.

3.0 COMBUSTION DEVICES

The electrical generating devices discussed under this heading are gas turbines, steam turbines, and magnetohydrodynamic generators (MHD). Of these three devices, gas turbines and MHD can use carbonaceous fuels as well as hydrogen. The steam generator, as considered in this report, is a device that can use only Case A or Case C fuel with high purity oxygen (probably >95%).

3.1 Present Status

3.1.1 Gas Turbines

Of the electrical generating devices considered in this report, gas turbine generators are the only ones that are commercial and, in their simple open cycle version, have a large amount of operating experience. The extent of the use of these machines is illustrated in a two-part article in a recent issue of Gas Turbine International.⁵

The advantages, disadvantages, cost and probable trends in improvement are known for gas turbines. Since this is not the case for other generating devices considered, only qualitative or perhaps speculative cost estimates can be made for these other devices. The principal uncertainty centers on the extent of experience of these various generating units. The manufacturing capability for gas turbine is large, and turbine operating experience in utility systems is extensive.

The industrial gas turbines are derived from the aircraft jet turbine technology. As applied to the electric utility industry, gas turbines have nominal maximum power ratings with the maximum being about 8% higher than the nominal. The utilities tend to operate the turbines at the maximum rating since the primary function of the turbines is to meet the short duration peak demand.

Among the factors influencing the frequency of overhaul for utility gas turbines, the three major ones, in order of decreasing importance are

Table 2.1 Summary of Cost (\$/kW) and Efficiency (HHV) Data

	Case A	Case B	Case C	Case D
<u>Acid Electrolyte</u>				
State of Art	\$160 44%	\$225 42%	\$225 42%	\$225 39%
Future	\$160 51%	\$225 47%	\$225 47%	\$225 46%
<u>Solid Polymer Electrolyte</u>				
State of Art	\$270 51%	\$600 44%	\$600 43%	\$620 43%
Future	\$130 51%	\$200 44%	\$200 43%	\$220 43%
<u>Base Electrolyte</u>				
Future High Cost	\$160 54%	- -	- -	- -
Future Low Cost	\$90 60%	\$110 52%	? ?	? ?
<u>Molten Carbonate Electrolyte</u>				
Future	- -	- -	- -	\$225 51%
<u>Solid Oxide Electrolyte</u>				
Future	- 47%	- 45%	- 45%	- 44%

- 1) Type and quality of fuel
- 2) Quality of air
- 3) Level of applied thermal stress

Most utility turbines use petroleum distillate fuels. Experience in the utility field has demonstrated that there is not only a detrimental influence due to metals such as vanadium and sodium in the distillate, but also distillate fuels, per se, have a more detrimental effect on the turbine blading than does natural gas. For example, one major utility indicated that 1 hr of operation burning diesel oil fuel results in a wear equivalent to 1.43 hr of operation burning natural gas. The use of the hydrogen fuels considered in this study will cause no more wear than the use of natural gas. Contaminants in air have an effect on the blading similar to metal contaminants in the fuel. This problem is especially severe where salt water mists are in the air. A thermal stress problem arises largely from rapid startup from a cold state. This type of startup tends to be the rule, not the exception, and is independent of the type of fuel.

Gas turbines have operated in utility service for about 10 years and, while this is not a desired lifetime for turbines, it is sufficiently long to provide the judgement that a 20-30 year lifetime will be achieved. To a large extent, the utility turbines are used in peaking service and thus operate less than 10% of the time. They tend to be placed on line from a cold start within short times (<5 min) and, to meet the reliability requirements for rapid on-line service, the turbines are quite frequently started just to check their startup reliability. This set of conditions plus those noted previously on the influence of fuel and air quality tend to decrease the average thermal efficiency of the turbines with time. In some cases, this decrease may appear exaggerated when the startup check operations are frequent and the amount of power generated is quite low.

The types of generating units using gas turbines considered in this report are the simple open cycle and the unfired combined cycle, since these are the two versions of gas turbines units with some utility acceptance. In addition, these gas turbines cover the probable range of cost and efficiency for all types of gas turbines, so that for purposes of this report additional study was not applied to versions such as regenerative or fired combined cycles.

There are at least three U. S. builders and suppliers of large gas turbine generator systems. Models of simple open cycle are available to about 50 MWe output and unfired combined cycles to about 85 MWe. The thermal efficiency of the latest open cycles is about 27% (HHV) during initial operation and for the unfired combined cycle about 42% assuming the use of petroleum distillate fuels⁶ (about 38% with hydrogen fuel). The operating experience of utilities with distillate fueled turbines in peaking service shows a drop as much as 25% in thermal efficiency during their operating life, most of this coming in early operations.

Gas turbines exhibit a variable thermal efficiency over their operating range, approaching zero at very low loads. Recently four bidders⁷ were asked to quote heat rates for base load, three-quarters-base load and half-base load operation using No. 2 distillate fuel. At three-quarters load, the thermal efficiency decreased to 85-95% of base load and at half load to 76-86% of base load.

Gas turbines can use any of the fuels considered or implied in this report. The only requirements are that the sulfur content should be less than 1% and that the concentration of various metals such as vanadium, sodium and potassium should not exceed 0.5 ppm.

3.1.2 Steam Turbines

A steam turbine-generator unit considered for the utilization of hydrogen fuel in the near term would probably consist of a hydrogen oxygen combustor; the combustor would be connected directly to an existing steam turbine and would produce steam conditions, using water injection, that match the turbine's allowable temperature and pressure conditions. In the longer term, such devices would utilize gas turbine technology to reach much higher temperature operation ($\sim 3000^{\circ}\text{F}$ or 1650°C), also in a condensing steam cycle.

Some studies have been made of such generating devices, and developments have been carried out to adapt rocket technology to the hydrogen combustors.

Steam turbine development is quite advanced, and a great deal of operating experience with machines available in sizes over 1000 MWe has been accumulated. Turbines have operated with steam pressures to 5500 psi and 1200°F (650°C), although recent manufacturing and utility experience has been with maximum operating conditions of about 2400 psi and 1050°F (570°C). The maximum operating temperatures are influenced more by restrictions on boiler operation than on turbine operation.

Although there are no hydrogen-oxygen steam turbines operating or planned, an operable machine could be set up in the near term by adding a hydrogen-oxygen combustor to an existing turbine. Experience within the utility industry has shown that boiler lifetime is frequently shorter than turbine lifetime and occasionally the turbine is in a condition of acceptable operability. Many of the turbines being retired from use today due to a unusable boiler are in the size range from 10 to 50 MW and have design operating temperatures in the range from 700 to 900°F (340 - 480°C). Such machines should have a thermal efficiency of at least 30% using hydrogen-oxygen fuel. Since the generating unit temperatures tend to have been fixed by the boiler rather than the turbine, an examination of the turbine design conditions and materials may allow operation at some temperature higher than the initial design temperature.

The efficiencies quoted for these generating devices are based on the assumption that the hydrogen and oxygen feeds are maintained at operating pressure. Two points should be noted in conjunction with this assumption. The first is that in actual operation, the efficiency will be reduced by an amount equal to the power consumed for raising the feed gases to operating

pressure. The second point is that the system efficiency would be higher than that for a fossil-fuel-fired boiler, because the efficiency penalty of 15% associated with the stack gas loss of the boiler would not be incurred. One situation currently being studied is the retrofitting of a 107 MWe steam turbine (1.2×10^6 lb steam/hr at 1265 psia, 925°F) which has a heat rate, as a coal-fired unit, of 11,000 Btu/kW-hr(e); this value is equivalent to a thermal efficiency of 31%. The thermal efficiency of this unit when equipped with a H_2 - O_2 combustor might be as much as 35%.

3.1.3 MHD

MHD development is in an early R&D phase. Although much of the U. S. work in the past has involved liquid or gaseous fossil fuels, the principal emphasis in the U. S., at present, seems to be toward the direct use of coal. The gases to an MHD generator must be at a temperature of at least 4500°F (2480°C) and contain some vaporized seed material, such as a potassium or cesium salt, to make the gas conductive. The coal fuel studies are not completely applicable to hydrogen fuel since the molten ash forms a somewhat protective barrier on the inner surface of the MHD device. The ash in the coal probably has a detrimental effect on the efficient recovery of the seed material. A clean gaseous fuel, such as hydrogen, would allow relatively easy recovery of the seed material. Studies and experiments are being conducted at NASA-Lewis on the H_2 - O_2 MHD generator.⁸

Significant experiments have been carried out both in the U. S. and U.S.S.R.⁹ Experiments in the U. S. have had operating periods up to 100 hr at about 300 kWe and at power levels as high as 32 MWe for one minute. One U.S.S.R. experiment had an operating time of 300 hr.⁹ Although these experiments have established feasibility, they have also demonstrated the need for considerable experience in the areas of materials, fabrication, design, and operation to establish the economics of items such as equipment lifetime, and acceptable operating and maintenance costs.

3.2 Future Developments

3.2.1 Gas Turbines

The next generation of commercial gas turbines is in the testing phase. These machines will product 75-85 MWe in simple open cycle versions with a thermal efficiency of about 30%. The inlet gas temperature to the turbines is about 2000°F (1100°C), and air-cooled blades are used in the first stages.

The potential of gas turbines for industrial applications is probably assured for operations involving turbine inlet temperatures up to about 2500°F (1370°C). This temperature is about the upper limit for the present air cooling techniques. Development of blading materials and coatings for such operating temperatures is also reasonably advanced. At an inlet temperature of 2300°F (1260°C), the best turbine thermal efficiency would be about 34% for the simple open cycle and 42% for the unfired combined cycle.⁷

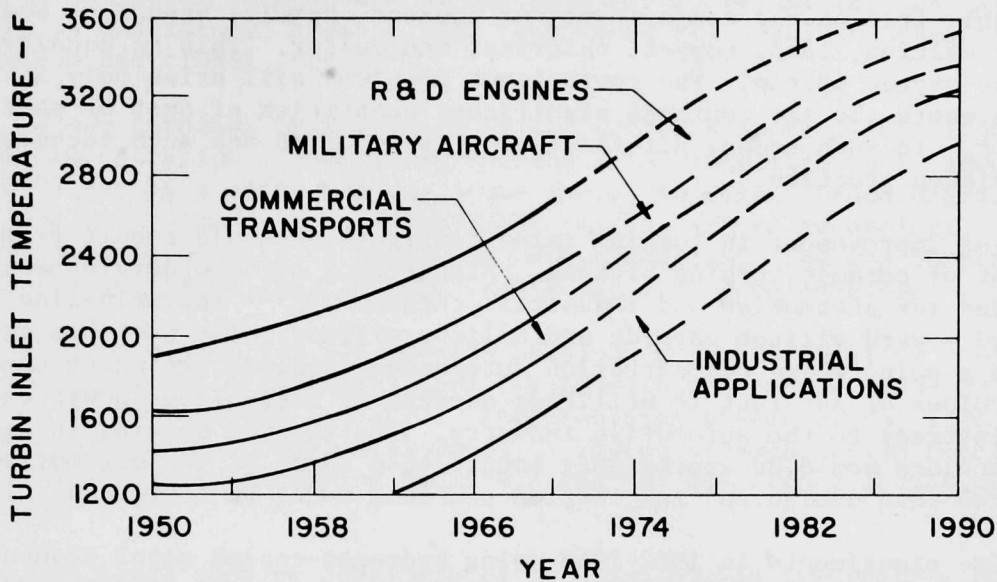


Fig. 3.1 Progress in Increasing Turbine Inlet Temperatures⁷

Figure 3.1 illustrates the actual and projected progress in increasing the turbine inlet temperature. In the time period considered in this report, the projection shows that a temperature of 3000°F (1650°C) may be reached by 1990. This temperature should yield a thermal efficiency of about 35.5% for the simple open cycle and 46% for the unfired combined cycle using hydrogen fuel.

These improvements in cycle efficiency with increasing turbine inlet temperature would be accompanied by the disadvantages of added system complexity and longer startup times from cold start or greater expenditure of energy to keep the system warm for either rapid startup or spinning reserve status.

As the turbine temperature increases, an increase is also needed in the pressure ratio. Already, the compressor pressure ratios have reached 24:1 in the U. S. and the developments required to reach 30:1 are reasonably assured. Compressors with 50:1 ratios are operating in Europe.

Blade cooling by the use of air is already an established practice in aircraft turbines. This technique should be acceptable up to inlet temperatures of about 2500°F (1370°C) and should be adaptable to utility turbines. Blade cooling by the use of water or liquid metals is more difficult. However, for industrial application, where space and weight restrictions are of low importance, the use of liquids for blade cooling should not be an overwhelming technical problem.

Coatings that provide oxidation resistance for metal blades are already in use. The life of these coatings is dependent on the thermal stress and the

amount of contaminants contained in the gas. Thermal stress can be controlled by the rate of startup. The level of contaminants in the fuel and air must be controlled prior to inlet to the combustor. Hydrogen fuel should be acceptably free of the contaminants of concern, namely, vanadium, sodium, potassium, calcium, lead, copper, chlorine, and sulfur. This is equally true of the oxygen stream. The contaminant problems will arise only in those localities where the air contains significant quantities of dust or salt water vapor. In such areas, air filtration is required and such techniques are established practice.

A major improvement in turbine inlet temperature should result from the development of ceramic turbine blading. Significant ceramic developments are being funded for automotive and industrial turbines.^{10,11} The main-line effort is directed toward silicon carbide and silicon nitride. The work has progressed to a point where demonstration automotive turbines are under construction. Turbines of interest to utilities operate at much higher power than those of interest to the automotive industry. The turbine blading in the utility machines would be appreciably longer than those of the automotive turbines and thus design and fabrication problems would be increased.

Turbine experiments in 1962-1963 using hydrogen-cooled metal blades led to successful operations with a maximum blade temperature of 1251°F (677°C) and a maximum turbine inlet temperature of 4150°F (2290°C). Hydrogen-air was the turbine fuel and about 70% of the hydrogen, in gaseous form, was used for blade cooling prior to combustion.¹² This approach to temperature control of blading increases the allowable cooling options.

The use of hydrogen fuels in gas turbines would be expected to result in a wear rate no greater than is observed in natural-gas-fueled turbines. Filters have been developed that effectively control the air contamination problem at an acceptable cost (<\$10/kW). Thermal stresses are induced during rapid startup; but since this situation will still exist in the future, no reduction in frequency of overhaul will come about from thermal stress considerations with the advent of hydrogen fuels. Operation of turbines in utility peaking service has resulted in overhaul intervals of 1000 to 1500 operating hours. The use of hydrogen fuels and filtered air should increase this interval to at least 3000 operating hours.

In summary, the developmental potential of gas turbines using hydrogen fuel is good for machines having thermal efficiencies up to about 50%. It appears reasonable to expect such developments within two decades. The base technology is well established and the research to achieve the improvements necessary for higher efficiencies is under way. However, as the gas turbine temperatures and complexity (simple open to combine cycle) increases, the cost and operating characteristics tend toward those of an intermediate service use rather than a peaking use.

3.2.2 Steam Turbines

The potential for the H₂-O₂ steam turbine is viewed in two parts; one is related to the combustor and the other to the turbine.

The combustor technology has a good established base in the rocket industry. Techniques of construction, feed control and chamber wall cooling are established. The nature of the problems to adjust turbine inlet temperature is understood; however, the techniques for resolving these problems required additional work.

Steam turbines that operate at temperatures above 1200°F (650°C) need some demonstration. Increasing turbine inlet temperatures to about 1500°F (820°C) may be a minor extrapolation since, in effect, such operating conditions have already been established in gas turbine technology. The steam turbine would operate at pressures much higher than the gas turbines, and thus the design of the pressure casing may pose some problems.

The potential for the turbine portion of the H₂-O₂ fired steam turbine system is essentially established for temperatures up to 1100-1200°F (600-650°C) at any desired pressure. The remaining developmental item is the combustor. With combustor development, a hydrogen-oxygen steam turbine system could be constructed having about 45% thermal efficiency operating at 1200°F (650°C).

The steam turbine developments to allow higher temperature operation will probably make use of the technology of gas turbines which are already operating at higher temperatures. A steam atmosphere with a small amount of excess oxygen would not be expected to be more corrosive than the combustion products from fossil fuels when a large excess of air is present. Consequently, the use of gas turbine blading materials in steam turbines should be satisfactory for uncooled blade operation to about 1500°F (820°C). Such a development is considered a small extrapolation over present practice.

Since the control of combustion mixtures to exact stoichiometric proportions is not practical, the controls would probably be set to maintain a small surplus of oxygen. This surplus should be kept low to avoid a significant pumping penalty to remove the noncondensable gases from the system.

The design of steam turbines can probably be adapted to include cooled blades such as those as developed for gas turbines, which allow operation to about 2500°F. The cooling media could be saturated steam discharged from the blading into the turbine steam flow, water discharged into the steam flow through small cooling passages or pores, or recirculating cooling water. Such cooling techniques might be successful with operations above 3000°F (1650°C). If ceramic blade materials are successful in gas turbines, they should be equally successful in steam turbines.

With a steam temperature about 3000°F (1650°C), a thermal efficiency of about 57% is possible and at 2000°F (1100°C), a thermal efficiency of about 51% is possible. Both of these efficiency values assume that hydrogen and oxygen are available at the required pressure, the efficiency will be less by an amount equivalent to the pumping requirements. The magnitude of this pumping penalty will be dependent on the specific situation. For example, if the hydrogen and oxygen were available from liquid storage or from a large pipeline system in which the compressor inlet pressure could be assumed

fairly constant, and the compression ratio was about 4:1 for both gases, an efficiency penalty of about 3% would be incurred.¹³ However, if circumstances required local storage in high pressure tanks, greater pumping power would be required because major swings might occur in storage pressure or because a greater economic penalty would result from providing surplus gas storage to avoid the major pressure swings.

The control system for an H₂-O₂ steam turbine might be less complex, and certainly no more complex, than a combined cycle gas turbine since one rather than two turbines need to be controlled. Test experience on equipment to date indicates that fast response time for all levels of control is not a large problem. In fact, the close coupling between the point where the fuel gases are injected and the turbine, plus the fast control response of fuel gas, probably eliminates the need for the large turbine inlet cutoff valve.

In summary, the developmental potential of the H₂-O₂ steam turbine should be similar to that of the gas turbine since gas turbine materials and technology will be used. A possible first application of such a device would be to add a H₂-O₂ combustor to an existing turbine from a generating unit in which the boiler is no longer of value. Such a generating unit could serve as a peaking device provided that extremely short startup periods could be avoided. However, as with the gas turbine, by the time such H₂-O₂ steam turbine devices are developed to high temperature-high efficiency models, the system complexities may have reached a point where the costs and operating characteristics of generating units are approaching those of base load nuclear or fossil units.

3.2.3 MHD

The potential of MHD generating units is high when expressed in terms of thermal efficiency, which is in the range of 55-60% using bottoming cycles.^{8,9} Although the possibility of attaining such efficiencies warrants research to establish economic and technical feasibility, the probability of this being accomplished within the next two decades is low, in our judgement. The materials and design problems to handle these very high temperature gases and the need to recover a large fraction of the seed material for recycle are formidable.

Because the judgement of this review is that MHD will not reach a commercial stage within two decades, no attempt has been made to review the probable content of a research and development program that might be aided by funds allocated to promote the development of hydrogen-fueled devices. Neither was any attempt made to speculate on the possible power costs from an H₂-O₂ MHD device.

3.3 Costs

3.3.1 Gas Turbines

The capital cost of installed gas turbine-generator units is 90-130/kW for the simple open cycle for units of 50-60 MWe output and \$170-225/kW for unfired combined cycle units of 75-85 MWe output. These costs are

dollar values at the beginning of 1975. Figure 3.2 shows cost projections⁷ based on 1970 dollars. The figure is included because it illustrates a manufacturer's expectation that, in terms of a constant total market, gas turbine costs are expected to be relatively constant, with inflationary trends as projected in the early 1970's being offset by factors such as larger turbine sizes and various developments improving overall thermal efficiency.

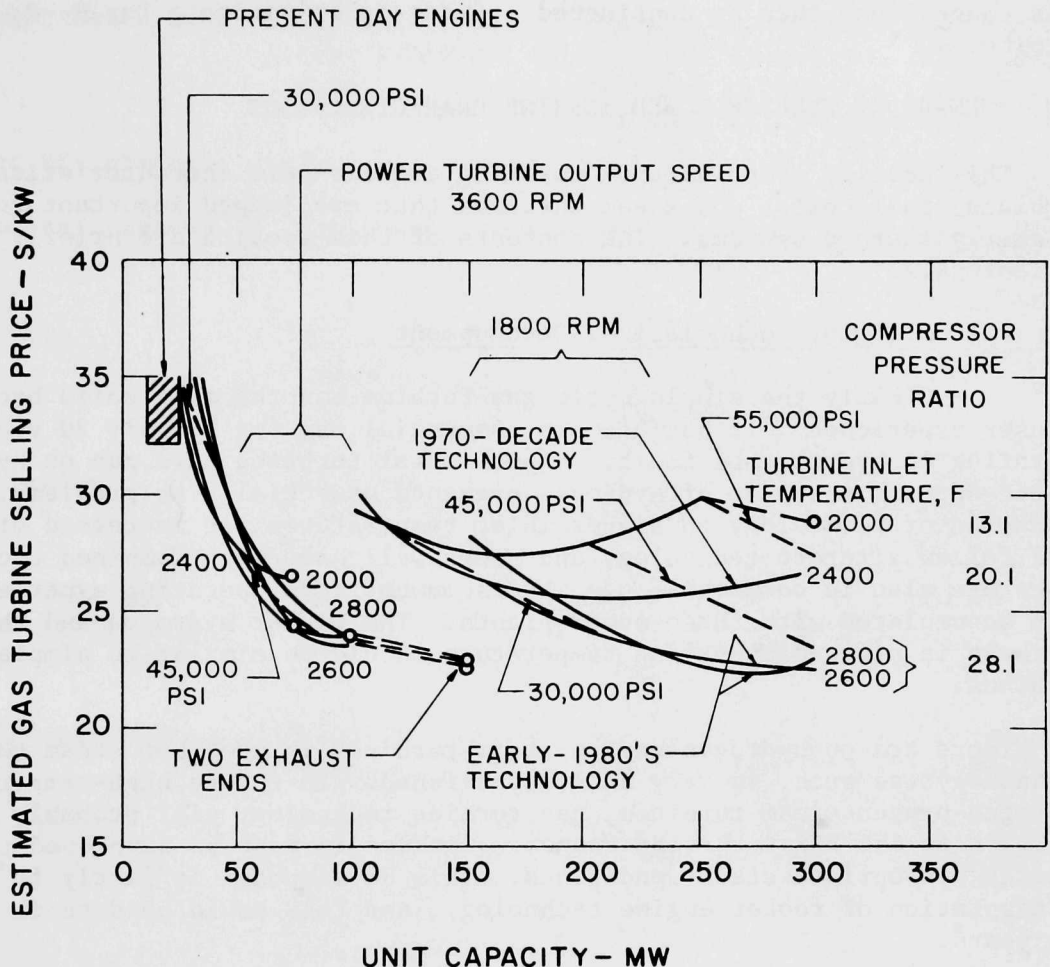


Fig. 3.2 Gas Turbine Selling Price⁷

3.3.2 Steam Turbines

Although costs comparable to those available for gas turbines are not available for H_2-O_2 steam turbines, some perspective can be supplied. Two approaches were used to estimate costs for steam turbines: one, retrofitting a combustor to an existing turbine; the other, building a completely new plant.

A retrofit installation on an amortized turbine should involve no more than \$50/kW of new capitalized costs even for a small turbine.

In an attempt to obtain some perspective for the possible capital cost of a new H_2-O_2 steam turbine, calculations were made using the ORCOST code¹⁴ for a gas-fired steam generator plant in the size range from 200 to 500 MWe.¹⁵ These costs, based on 1975 dollars, were \$416/kW for the 200-MW and \$283/kW for the 500-MW size. Although the simplified code did not give sufficient detail to factor out the steam boiler with all boiler auxiliary equipment and building accounts, this factor was estimated to be a third of the total. The price range with these estimated boiler accounts subtracted is \$277-189, and this range might then be considered a first-order estimate for H_2-O_2 steam turbine.

4.0 SUMMARY OF FUEL CELL AND TURBINE CHARACTERISTICS

This section compares the operating and economic characteristics of gas turbines, fuel cells, and steam turbines that are judged important for use in energy storage systems. The contents of this section are briefly summarized in Table 4.1.

4.1 State of Technological Development

Clearly the simple cycle gas turbine has the most solid background of user experience. It has been in commercial use for roughly 20 years, operating on hydrocarbon fuels. Experimental turbines have run on hydrogen, and it appears that use of hydrogen presents essentially no problems. Extension of technology to higher inlet temperatures for increased efficiency will follow aircraft technology and seems well assured. Combined cycle turbines are also in commercial use, but somewhat less operating experience has been accumulated with these power-plants. The use of hydrogen and the increase in allowed operating temperature should be similar to simple cycle turbines.

There are no hydrogen-oxygen steam turbines in use, but steam turbine technology, as such, is very well established. In future high-temperature hydrogen-oxygen steam turbines, gas turbine technology will probably be adapted, at least in the first turbine stages. Combustors must be developed to provide appropriate steam conditions. This development is likely to proceed by adaptation of rocket engine technology, and this could be done in only a few years.

The maturity of terrestrial fuel cell technology ranges from the early R&D stages (solid oxide) through late engineering stages (phosphoric acid). The first commercial fuel cells may be used as early as 1980. Second generation cells (CO_3^{2-} , aqueous base cells) might be commercially available in the mid 1980's.

4.2 Efficiency

At any given date, predicted fuel cell efficiency depends mostly on the fuel and hence the type of cell that is used. Predicted rated load efficiency varies from about 38% for acid cells operating on carbonaceous fuel and air (in the present or near term) to 60% or more for base electrolyte cells operating on hydrogen and oxygen (estimated date, about 1985). It

Table 4.1 Comparison Summary of Generators

	Fuel Cells	Gas Turbine	Steam Turbine
State of Technological Development	Not commercial	In commercial use	Combustor and integration; not commercial
Efficiency, Rated Load	Generally high (See Section 2.3)	Simple cycle: 25% now, 36% future Combined cycle: 38% now, 46% future	30% retrofit 56% future
Part Load Efficiency	Excellent	Poor	Fair
Environmental Factors	Excellent	Some NO _x using air; noise high	Noise high; thermal discharge to water
Startup Time	Varies with cell temperature	Simple cycle, fast, (2-15 min) Comb. cycle, slow (2-30 min)	Very slow
Load Following	Excellent, all loads	Excellent over smaller load range	Excellent over smaller load range
Effect of Size on Cost and Efficiency	No effect above 0.2 MW	Simple cycle sensitive up to 25 MW; Comb. cycle up to 50 MW	Rather sensitive
Interface with Storage	Pressure not required	May require pressurized feed	May require pressurized feed
Overhaul Cycle	Gradual degradation requires infrequent component replacement	Requires frequent periodic overhaul	Requires less frequent overhaul
Use of Alternative Fuels	Requires some fuel conditioning	Excellent, little difficulty	Inappropriate

would be possible to improve these efficiencies at added capital cost by adding cells in series to the generator. Efficiency is quoted at "end of useful life." Efficiency might be one or two percent higher in a new unit.

One of the most important things to note about fuel cell efficiency is that it increases as the generator is backed off from full load. Half-load efficiency might be as much as 120% of rated load efficiency. This effect is inherent in all fuel cell systems, but can be masked by "parasitic" losses to associated systems, such as fuel conditioners. Nonetheless, in a well designed system, even one operating on hydrocarbon fuel, rated load efficiency should at least be maintained down to 25% of rated power.

Efficiency (and cost/kW) of fuel cell stacks should be essentially independent of size. Present inverter technology requires that output dc voltage from the fuel cell stack be relatively high, so that generators of less than about 0.2 MW begin to suffer some loss of efficiency.

Efficiencies of simple cycle gas turbines operating on hydrogen at present-day inlet gas temperatures of 1600°F (875°C), would be about 25%. By 1990, inlet temperatures might be 3000°F (1650°C) in commercial units, giving rated load efficiencies of about 36%. Efficiency decreases at part load, typically being 85-95% of rated efficiency at three quarters load and 75-85% of rated efficiency at half load, then dropping to zero at very low load. These efficiencies are for new units. Some degradation is to be expected as the unit ages, but it should be small if hydrogen and well-filtered air are used.

At rated load, combined cycle efficiencies would be about 38% at present-day inlet temperatures, and about 46% when 3000°F inlet temperatures are used, probably by about 1990. Efficiency reductions at part load would be similar to those of simple cycle turbines.

Steam turbine efficiencies would vary from about 30% for a generator with a combustor retrofit of an existing turbine to about 56% for a highly advanced, specially developed steam turbine system with 3000°F inlet temperatures. Part-load efficiencies should be considerably better than gas turbines, but nonetheless would be less than at rated load.

4.3 Environmental Factors

Severe environmental degradation is not expected from any of the generators, but comparison of environmental characteristics is probably important for relatively sensitive sites, such as in residential or commercial areas. For gas turbines, the only chemical pollutant expected for operation with hydrogen is NO_x. Noise levels are predictably greater for turbines than fuel cells. Thermal discharge from simple cycle gas turbines and fuel cells, which do not require cooling water, is usually to the air and hence is not a "pollution problem" in the ordinary sense, that is, a thermal upset of the ecological balance in streams and lakes. Steam turbines and combined cycle gas turbines use water to condense the steam and thus may cause environmental problems when once-through condenser-water systems are used. Cooling towers can alleviate this situation; however, they are expensive and reduce efficiency somewhat.

4.4 Start-up Time

The time required to bring a generator on-line is largely a function of the mass of the unit, the temperature to which it must be heated, and the materials of construction. Steam turbines as used in utilities are quite slow starting; units having capacities of a few tens of megawatts would require on the order of an hour to reach operating conditions from a cold start, consuming fuel in the process. Simple cycle gas turbines can be started in two to fifteen minutes, but very rapid starts impose severe thermal stresses on the machinery. Combined cycle generators could start up as simple cycle machines with reduced efficiency, with the steam turbine being brought on-steam when it is ready. Start-up times for fuel cells would probably vary considerably more widely than those of turbines. Low-temperature systems, such as aqueous base electrolyte cells operating on hydrogen, would probably be able to pick up a load almost immediately, depending on design details. Intermediate-temperature cells like the phosphoric acid electrolyte cells might require several hours to come to temperature. The situation would be correspondingly worse for molten carbonate and solid oxide cells. When fuel conditioning equipment is required, warm-up of this equipment may be the limiting factor. The efficiency of fuel cells themselves is inherently very high at low power output, but the temperature of operation and rate of heat loss determine whether it would be possible to keep them warm for intermittent operation. This characteristic is so dependent on details of design that it is not possible to evaluate the penalty for keeping cells at temperature. It does, however, emphasize the desirability of low temperature cells for intermittent operation.

4.5 Response to Change in Load

Fuel cells generally may be expected to respond nearly instantly to variations in load over their entire output range. Turbine systems may also be expected to respond well over a smaller range, and can be designed to have wide output ranges. It is probably not desirable to operate turbines far from rated load for reasons of efficiency, at least in large networks, because much of the total variation in demand can be met by dispatching generators as demand changes. Use of fuel cell generators in a network would nearly eliminate the need for turbine generators to operate at output levels lower than their maximum efficiency level.

4.6 Effects of Size

Costs and efficiencies of fuel cell generators are rather insensitive to size, and no appreciable scale advantages are seen above about 0.2 MW. The size effects are due mostly to power and fuel conditioning systems. For aerodynamic reasons, turbines in general become more efficient with increased size. This effect is noticeable up to about 25 MW for simple cycle gas turbines. Steam turbine efficiencies are apparently more sensitive to size, and efficiencies level out at still higher power ratings.

4.7 Interface with Hydrogen Storage Unit

Two factors are of concern in considering the effect on efficiency of the generator/storage interface. First, a generator that requires hydrogen fuel at some pressure higher than that of the storage system must pay an efficiency penalty for pumping energy. This may be of some concern with high temperature (hence high pressure) turbine generators coupled with metal-hydride or other low pressure storage. Second, in metal hydride storage systems, there must be sufficient waste heat at a high enough temperature to release hydrogen from the hydride. This is likely to be of concern only with steam turbines or possibly with low temperature fuel cells. If waste heat is not available for this purpose, some minor penalty in overall system efficiency would be paid to release the hydrogen.

4.8 Overhaul Cycle and Maintenance

The kinds of maintenance necessary to keep a generator operating economically throughout its useful lifetime are different for turbines and fuel cells. Turbines typically require periodic major overhauls. Depending upon the severity of service and the type of fuel, an overhaul might be required every one to three thousand operating hours for a peaking simple cycle gas turbine, or every two or three calendar years for a baseload steam turbine. This maintenance is required to prevent severe loss of performance or failure. Fuel cells will probably undergo a gradual loss of performance that is substantially independent of load demand. Overhaul or major component replacement would be required periodically. This period between major overhauls or component replacements is estimated to be 40,000 hr at temperature for phosphoric acid cells. Lower temperature cells might be operated for considerably longer times before replacement of major components becomes economical. Only operating experience will establish comparative maintenance expenses, but turbines used for peaking would most likely have higher maintenance expenses than low or moderate (<200°C) temperature fuel cells used for similar duty, and would certainly incur higher expenses than gas or steam turbines with less severe duty cycles.

4.9 Use of Alternative Fuels

For ease of use with carbonaceous fuel, gas turbines are clearly superior. Fuel cells would require varying amounts of fuel-processing equipment, depending on the fuel and the type of cell. Steam turbines are restricted to the use of fairly pure hydrogen and oxygen, and would require an oxygen source as well as fuel conversion equipment; this restriction makes steam turbines unsuited for use with carbonaceous fuel.

5.0 RECOMMENDATIONS

5.1 Systems Studies

As has been pointed out previously, any hydrogen energy storage system must be evaluated against other systems if one is to make reasonable choices among alternative means of achieving desired goals. Studies such as this, which examine only one part of a system, provide only part of the data

necessary to choose a course of action. Therefore, the recommendations herein are all contingent upon the results of future comparisons of energy storage systems. It is essential that these comparisons be made, and that the need for a specific type of hydrogen energy-storage system be established before implementing any of these recommendations for the development of generating devices.

5.2 Match of Generators to Storage Systems

We have tried throughout this report to provide a sufficient description of each generating technology so that an appropriate choice of generator can be made for any proposed hydrogen energy storage system. Several representative or illustrative systems are considered to indicate the range of storage systems that might be developed, and especially to show which kind of generating device is preferred for any general kind of storage system. These illustrative systems are described below, and the results are summarized in Table 5.1.

5.2.1 Systems with Storage of Electrolytic Hydrogen and Oxygen

In this system, off-peak power is used to electrolyze water. Both the hydrogen and oxygen are stored, and then recombined to generate electricity during periods of high electrical demand. Because the capital cost of this system must be charged to the cost of peak power at a relatively low capacity factor, and because generator efficiency has a dominating effect on overall system size and cost, this system requires a very efficient generator. The most appropriate generators are, therefore, considered to be the aqueous base electrolyte fuel cell and the advanced steam turbine, with the aqueous acid and membrane electrolyte fuel cells a second choice. Solid oxide fuel cells are tentatively ranked with acid and membrane electrolyte cells, since this technology is insufficiently advanced to state with certainty that they would be capable of intermittent operation, and that recovery of their high-grade waste heat would be feasible. It is assumed that steam turbines could perform as a peaking devices if operation of the units were scheduled to allow warm-up.

5.2.2 Electrolytic Systems without Oxygen Storage

This second system is similar to the first (storage of hydrogen and oxygen), except that oxygen is not stored. This system has lower capital cost and greater flexibility in location but it requires the generator to operate on air. Efficiency must still be high, and thus the aqueous base electrolyte fuel cell remains the first choice if air operation can be achieved. The membrane, solid oxide, and acid electrolyte fuel cells are more attractive than in the oxygen storage system because of the ease of operation on air. Combined cycle turbine systems should have the necessary efficiency, but may not be well adapted to the short generating periods that may be expected in a pure storage system like this.

5.3.2 Systems with "Pure" Hydrogen from a Gasifier

The third system uses hydrogen from a central synthesis plant

Table 5.1 Illustrative Storage Systems^a

Generator	Earliest Commercial Availability	Electro- lytic H ₂ + O ₂	Electro- lytic H ₂ only	"Pure" Coal Derived H ₂		CO + H ₂		Dual Fuel	
				Central	Dispersed	Central	Dispersed		
Fuel Cell									
Acid	1980	B	B	A ^d	A ^d	B ^{b,d}	B ^{b,d}	A ^{b,c,d}	A ^{b,c,d}
Membrane	1983	B	B	B ^e	B ^e	C ^{b,e}	C ^{b,e}	B ^{b,c,e}	B ^{b,c,e}
Base	1983	A	A ^{h or i}	A ^h	A ^h	A ^{b,h}	A ^{b,h}	A ^{b,c,h}	A ^{b,c,h,i}
Carbonate	1985	-	-	-	-	A	A	-	-
Oxide	1990	B	B	A	A	A	A	B ^c	B ^c
Gas Turbine									
Open cycle	1977	-	D	D	D	D	D	D	D
Combined cycle	1977	-	C	A	C	A	-	B	-
Steam Turbine	1978 ^g	A	-	C ^f	-	D ^{b,f}	-	D ^{b,f}	-

^aThe letter designation in the last eight columns represents a relative ranking of the generator systems with A being most suitable and D being least suitable.

^bRequires water gas shift reactor.

^fRequires O₂ plant.

^cRequires reformer.

^gCombustor retrofit to existing turbine.

^dRequires some CO removal.

^hAdvanced base cell technology only.

^eRequires extensive CO removal.

ⁱRequires CO₂ removal.

such as a coal gasifier. The synthesis plant would presumably run continuously and thereby greatly reduce capital charges. Also, it seems likely that this kind of system would have a relatively high electrical capacity factor, and would be used to meet some intermediate loads as well as peak load. It is assumed that the hydrogen would be purified to the Case C specification of 1% carbon oxides and <1 ppm sulfur.

In the discussion of generators for this system, two situations arise: in one the generator is located centrally (near the synthesis plant), and in the other the generators are dispersed and fed by a pipeline which might also act as a storage device. For a centrally located generator, combined cycle generators are judged to be equivalent to acid electrolyte fuel cells, because unit sizes are likely to be very large, and because noise and possible NO_x emissions would be less of a problem than in a location close to load centers. For dispersed locations, fuel cells are preferred. Acid electrolyte cells are more appropriate than membrane cells because of greater CO tolerance. Solid oxide fuel cells are rated highly on a provisional basis, but this rating is dependent upon the ability of the units to meet intermittent demand and to use their high-grade reject heat successfully. The technology is too immature to allow accurate evaluation of these points. Solid oxide fuel cells are likely to be more desirable as capacity factors increase.

Conventional base electrolyte fuel cells would require extensive removal of carbon oxides from both air and fuel streams. Advanced base electrolyte systems that make provision for periodic electrolyte regeneration, currently under development at Exxon, would be suitable for use with Case C fuels. Steam turbines could be used, but would require construction and operation of an oxygen plant for intermittent service. Simple open cycle gas turbines would be inexpensive and flexible, but too inefficient for use with this fuel, which would probably be quite expensive.

For dispersed-site generation in this kind of system, fuel cells are preferred over combined cycle plants because of environmental and siting factors, and because unit sizes seem likely to be smaller than for a centrally located generator. As in the case of centrally located generators, solid oxide (conditionally) and acid electrolyte fuel cells are preferred, followed by membrane electrolyte cells.

5.2.4 Systems with Unshifted Fuel from a Gasifier

This fourth illustrative system is similar to the third ("pure" hydrogen from a gasifier) except that the fuel from the gasifier is unshifted. It is a mixture of CO and H_2 , with some CH_4 . Sulfur compounds are postulated to be less than 100 ppm. Whether CO_2 is removed from the gas is essentially immaterial to the choice of generator, but presumably it would be at least partially removed if the gas is to be transported for more than a short distance. If CH_4 levels are greater than 1 or 2%, the fuel cell generators would probably require a reformer in order to utilize the energy content of the CH_4 . The choice of generators for this system is similar to that for the previous

system, except that molten carbonate cells could now be used, because sufficient CO_2 would be present in the anode exhaust to meet the cathode requirement for CO_2 . Molten carbonate fuel cells are thus favored for this application. Solid oxide cells are relatively more desirable than in the previous system because they require very little fuel processing.

For a central station generator, the combined cycle turbine, the molten carbonate fuel cell, and (conditionally) the solid oxide fuel cell are preferred as generators. Close examination of a specific system might allow discrimination among these, but this is not possible in a general discussion. The next choices would be acid electrolyte fuel cells and then membrane electrolyte fuel cells. The steam turbine would require extensive fuel processing and an oxygen plant, thus making it an unlikely alternative. Simple open cycle turbines suffer from lack of efficiency, but are probably still competitive with the steam turbine concept, or more attractive if fuel cost is not too high.

For dispersed generation in this kind of system, the same generators would be preferred, with two exceptions: (1) combined cycle generators would be less attractive than the fuel cell options, as in the previous system, and (2) simple open cycle turbines are clearly more feasible than steam turbines.

5.2.5 Dual Fuel Systems

The fifth illustrative system is a hydrogen storage system much like the first or second system, but its generators have the capability of utilizing a supplemental fuel supply, such as an alcohol or hydrocarbon fuel. Such a dual system would supply emergency or reserve generating capacity or could meet a need for intermediate generating capacity in addition to energy storage. In this kind of a system, the generator must be capable of operating on both pure hydrogen and carbonaceous fuel, and it must meet the needs, especially for efficiency, of the storage system.

The preferred generators are the advanced base, acid, membrane, and (conditionally) solid oxide electrolyte fuel cells, and the combined cycle turbine if the storage system does not include oxygen storage and the generator is centrally located. The steam turbine would require oxygen and considerable fuel processing for supplemental fuel operation. Simple open cycle turbines would not be efficient enough. Molten carbonate fuel cells would require supplemental CO_2 for hydrogen operation and are therefore not appropriate. Conventional base electrolyte fuel cells would require meticulous removal of carbon oxides from air and fuel streams, as well as extensive fuel processing to produce hydrogen; therefore, they are not likely to be used.

5.3 Recommended Developments

The developments recommended in this section are contingent upon establishment of needs for and feasibilities of the corresponding storage system, as discussed in Section 5.2. It is the consensus of the participants in this study that support of a technology rapidly becomes more expensive as that technology approaches the stage of manufacture of significant numbers of

units for commercial sale. Total cost to develop any of the technologies discussed, to the point where significant numbers of units have been sold, is likely to be hundreds of millions of dollars. On the other hand, support of basic research programs can be accomplished with funding on the order of \$100,000 annually.

It is not the intent of this report to comment on who should support what part of a development program. Rather, the stage of development and extent of present programs are pointed out, and the potential benefits discussed for each technology. In the cases where a technology can benefit significantly from previous, related work, this is pointed out. An example of the latter is the adaptation of rocket engine technology to hydrogen/oxygen combustors for steam turbines.

5.3.1 Fuel Cells with Aqueous Acid Electrolytes

These cells are highly versatile with respect to the type of fuel used, and are generally well suited to use in any of the hydrogen storage systems. They are currently entering the later stages of development prior to manufacture by the Power Systems Division, United Technologies Corp. They are being developed for use as generators with hydrocarbon fuels. Adaptation to use with hydrogen should be straightforward, provided that present development efforts can be carried through, and that generators are actually marketed. This technology certainly merits necessary support for use in several storage options described previously (see section 5.2), especially since it is a relatively near-term option.

5.3.2 Fuel Cells with Membrane Electrolytes

Much of the basic R&D work has been completed for this system, except for reducing cost and investigating operation on carbon-containing fuels; space-type hardware has shown excellent performance and life. The technology is not currently being developed at a significant rate, and is considerably further from commercial use than the acid electrolyte technology. These cells would be recommended if a need is shown for a relatively low-temperature hydrogen-air system as an alternative to aqueous base electrolyte technology. This type of cell has been developed at General Electric Co. There is some possibility that they will make significant advances, such as cost reductions, in ion exchange membrane electrolyzers which could be applied to fuel cells.

5.3.3 Fuel Cells with Aqueous Base Electrolytes

This type of cell has outstanding potential for use with electrolytic hydrogen, especially if oxygen is also available. Should this type of storage system look attractive, development of aqueous base cells is highly recommended. Cells of this general type are being developed in a joint U.S.-French venture by Alsthom-Exxon, with the intent of terrestrial application, using hydrogen containing substantial amounts of carbon oxides and ambient air. These developments appear promising, but are largely proprietary. It is clear that operation on air is expected, and that costs are expected to be low.

5.3.4 Fuel Cells with Molten Carbonate Electrolytes

Because of kinetic advantages associated with high operating temperature, these cells have excellent potential for use with carbonaceous fuels such as coal gasifier output, alcohols, or hydrocarbon fuels. They are not suited for use with pure hydrogen. Development of these cells is being actively pursued by Power Systems Division, United Technologies Corp. and the Institute of Gas Technology. Research has previously been conducted on this type of cell by several other organizations, both in the U.S. and abroad. The technology is estimated, at present, to be about five years behind aqueous acid fuel cell technology. Support of molten carbonate fuel cell technology is highly recommended if a system using carbonaceous fuel is to be developed.

5.3.5 Fuel Cells with Solid Oxide Electrolytes

Potential utility of these cells is high, because of their ability to consume a variety of fuels and because of the high temperature at which heat is rejected. The technology is only in its infancy, and formidable technological problems remain to be solved. For this reason it is difficult to predict with certainty whether these cells would be used only in physical conjunction with a gasifier, or whether they could be dispersed. Development is essentially at a standstill in the U.S., but some work is going on in Europe¹⁶ and Japan.⁴ Development efforts in the U.S. were carried out by Westinghouse, until a few years ago. The research funding needed in this system is relatively inexpensive: it is recommended that such support be given, at least until a better understanding is gained by the utility of these cells.

5.3.6 Gas Turbines

Gas turbines in simple and unfired combined open cycle are established commercial items of known cost, and considerable operation experience with fossil fuels is available. The developmental path is established for operation at higher temperatures and consequently higher efficiencies. Such developments are being carried out for military and commercial aircraft and for industrial use such as prime movers for natural gas compressors and electrical generators. These developments are directly applicable for hydrogen-fueled gas turbines. Consequently, the designation of funding for hydrogen fueled systems is not recommended, except possibly in one R & D area.

The possible exception is the development of ceramic materials and techniques for their manufacture to provide suitable high-temperature turbine blading. Ceramic blades offer the potential of major improvements in efficiency. However, prior to a commitment of hydrogen-system funds to ceramic blade development, a survey should be made to establish the state of this development to determine whether additional funds are required.

5.3.7 Steam Turbines

Considerations for development of H_2-O_2 steam turbines are evaluated on two bases: (1) the retrofitting of $H-O$ combustors to existing turbines, and (2) the development of H_2-O_2 combustors and advanced high-

temperature steam turbines is a larger effort. The combustor development should be similar to that for the retrofit consideration. The difference is related to greater system complexity and higher turbine temperatures and pressures. If a combustor is developed for retrofit to an existing type of turbine, additional developments for high-temperature steam turbines should be within the funding capabilities of suppliers.

The use of high-temperature gas turbine technology can contribute significantly to the development of steam turbines that can operate at high-pressure steam conditions. It appears that materials suitable for a gas turbine will be equally suitable for a steam turbine operating at the same turbine inlet temperature. The recommendation given for gas turbines involving a survey of the state of ceramic blade development, with possibly additional funding, applies equally to steam turbines. The major development effort will probably be in the design of turbine pressure casings with appropriate cooling, for units with high enough inlet steam temperatures to require such cooling.

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